एनटीपीसी लिमिटेड
(भारत सरकार का उद्यम)
NTPC Limited
(A Govt. of India Enterprise)
केन्द्रीय कार्यालय/ Corporate Centre

Ref No. 01.CD.737-D
Date: 15.05.2020

To,

The Secretary
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chanderlok Building,
36, Janpath,
New Delhi-110001

Subject: Comments of NTPC on Draft CERC (Terms and Conditions of Tariff)(First Amendment) Regulations, 2020

Sir,

Hon'ble Commission vide its notification dated 01.04.2020 has published he Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations, 2020 inviting views /comments/suggestions/objections from various stakeholders on the proposed draft amendment to the Tariff Regulations 2019.

In this regard, please find enclosed comments/ suggestions of NTPC on the Draft CERC (Terms and Conditions of Tariff) (First Amendment) Regulations, 2020

Thanking you,

Yours faithfully

(Rajnish Bhagat)
Executive Director (Commercial)

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1. ***12. Amendment of Regulation 30 of the Principal Regulation***

12.1. In the first proviso under Clause (2) of Regulation 30 of the Principal Regulations, the words "excluding additional capitalization due to Change in Law," shall be deleted and at the end of the said proviso, the words and expressions "or in the absence of actual loan portfolio of the generating station or the transmission system, the weighted average rate of interest of the generating company or the transmission licensee, as the case may be, as a whole, shall be considered;"shall be added.

12.2. A new clause, namely, Clause (3) shall be added after Clause (2) of Regulation 30 of the Principal Regulations, as under:

"(3) The return on equity in respect of additional capitalization due to emission control system shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or in the absence of actual loan portfolio of the generating station, the weighted average rate of interest of the generating company as a whole shall be considered;"

1. **NTPC's Comments:**

1.1 <u>Huge investment decisions already taken based on normative rate of return on equity : Proposed changes may not to be applied retrospectively:</u>

Based on provisions of Final Tariff Regulation 2019, which inter-alia provides that expenditure on account of change of law including ECS will be serviced at normal rate of ROE i.e @ 15.5%, NTPC Board has already accorded investment approval for installation of FGD system for around 48,000MW capacity, involving financial implication of around Rs 26,000 Crores and letters of award has been placed to successful bidders. Further NTPC's JV & Subsidiaries have also accorded investment approval for installation of FGD system for around 7,800 MW capacity, involving financial implication of around Rs. 5000 crores and letters of award have been placed on successful bidders.

The financial appraisal of the ECS expenditure has been done considering Debt Equity ratio of 70:30 and return on equity of 15.50%. The Board of Directors has taken Investment decision based on the above.. The financial appraisal reports have also been submitted to the lenders for arranging the loans. The lenders have also agreed to provide loans for financing the capital expenditure based on approved financial appraisal reports. It is submitted that now that Investment decisions have been taken and loans tied up, the tariff recovery provisions may not be changed retrospectively at this stage.

With the proposed amendment lenders may be reluctant to release the funds sanctioned, which will lead to difficultiy in execution of ECS schemes. This may ultimately delay the installation of the emission control systems and may also lead to the generators not being able to achieve the time-lines mandated by the Government.

Further, with return on equity available only equal to the weighted average rate of loan, it may not be financially prudent for any generator to deploy the equity, as equity always commands a greater return as compared to rate of return on debt. Due to the proposed amendment, generators may seek loans to fund the entire capex, resulting in passing the whole risk of the project to lenders, which the lenders may not accept.

This regulatory uncertainty would also hurt the sentiments of investors and deter investment in the sector. Accordingly,it would be more prudent not to apply the above provisions on stations/ schemes where Investment Approval has been accorded / loans have been tied up.

1.2 Hon'ble Commission had decided this Issue while framing the Tariff Regulations 2019 after due consideration

A brief background of the matter is summarized below:

A. Draft Regulations, 2019 issued by Hon'ble Commission proposed as under:

"a.Provided that Return on equity in respect of additional capitalization after cutoff date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station"

B. In this regard the Explanatory Memorandum to Draft Terms and Conditions for Tariff Determination 2019-24 issued by the Hon'ble Commission provided as under:

"*Para 2.5.6 :The Commission has also proposed to clearly segregate the a) additional capitalisation within the original scope and up to cut-off date, b) additional capitalisation within original scope and after cut-off date and c) additional capitalisationbeyond the original scope, in terms of treatment of these w.r.t rate of return on equity. It has been proposed that equity component up to 30% of the additional capital expenditure incurred after the cut-off date, whether within the original scope or not, shall be serviced at the weighted average rate of interest."*

"Para 11.5.13, the Commission intends to allow the existing rate of 15.50% in respect of the equity component (up to 30% or as approved by the Commission) of the capital cost up to the cutoff date only. In respect of any additional capitalization after cut-off date whether within or beyond the original scope of work, the equity component is proposed to be serviced at the weighted average rate of interest on actual loan portfolio. This provision is not proposed to be applied in case of additional capital expenditure on account of Renovation and Modernisation after useful life."

C. NTPC, in its submissions/suggestions on the Draft Tariff Regulations, 2019-24 (at page 47) submitted the following for consideration by the Hon'ble Commission:

"100% debt funding is not practical to source from the market. The additional capital expenditure incurred on projects is funded from both debt and equity. With regard to the implementation of the revised emission control norms, the cost of installation of Flue Gas Desulphurization (FGD) equipment is in the range of Rs. 40-75 lakhs per MW depending on unit size and configuration. Considering the overall portfolio of NTPC thermal plants where FGD is required to be installed, the total capital investment requirement for installation of FGD equipment would be approximately Rs.20000 Crores. Sourcing such huge quantum of funds only in form of debt is not possible. Therefore, additional capital expenditure on installation of FGD equipment will have to be necessarily funded by both internal resources / equity and debt.

In case the investment is sourced entirely on debt alone, the interest rate would increase as lenders would charge higher interest rate on loans in the absence of any equity participation. This would increase the supplementary tariff for the ECS. As a result, the benefit of reduction in tariff on ECS as intended by the Draft Regulations shall not materialize but shall be counterproductive."

D. Hon'ble Commission, after considering the stakeholders' comments/suggestions allowed RoE on additional capitalization expenditure @ 15.5% and in the Statement of Reasons to CERC (Terms and Conditions of Tariff) Regulations, 2019 has observed as below:

"The Commission has considered the stakeholders' comments/suggestions. The Commission is of the view that in cases where the additional capitalization has become necessary to comply with the 'Change in Law' event, normal rate of return of equity should be allowed instead of allowing rate of return on equity at weighted average rate of interest on actual loan portfolio. Therefore, first proviso to clause (2) of Regulation 30 has been revised suitably."

E. In this regard proviso to Regulation 30 (2) of Tariff Regulations 2019 provides as below:

"Provided that return on equity in respect of additional capitalization after cut-off date beyond the original scope excluding additional capitalization due to Change in Law, shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;"

As detailed above, Hon'ble Commission took a conscious decision after due consideration on the issue and allowed the return on equity on account of change in law and works within original scope after cut-off date to be serviced based on normal rate of ROE @ 15.5%.There have not been any change in the state of affairs since March 2019 when the Hon'ble Commission took this decision taking into views of all the stakeholders. Moreover, huge investment decisions and financing arrangement have been made for emission control systems considering rate of return on equity of 15.5% It is therefore submitted that Hon'ble Commission may not reverse its decision in this regard and continue to provide the rate of return on equity as envisaged in the Tariff Regulations 2019.

1.3 Regulatory uncertainty due to Hon'ble Commission revisiting the Regulation 30 of Tariff Regulations 2019

Power Sector projects are capital intensive and require certainty of revenue stream. Investment is undertaken by the Developer based on the investment risk perception, considering the existing policy and regulatory framework at the given point of time.

Lenders also need comfort in terms of certainty of timely and regular repayment of debt and interest thereon. Proposals of retrospective reduction in return allowed on capital cost pertaining to change in law including that of ECS will send an adverse signal and be detrimental for the investment sentiment in the country. This will increase risk perception, interest rates and consequently the consumer tariff which is not in line with the National Electricity Policy which provides as below:

"National Electricity Policy lays emphasis on the need for regulatory certainty to generate investor's confidence and as such any adverse changes in norms, if necessary, may only be made applicable for future investments/projects to minimize risk perception."

1.4 <u>Difficult to raise 100% Debt Financing for huge capital expenditure on ECS</u>

In addition to the issue of some developers reluctance to investing equity in a project as the same would be serviced at debt rate, it is very important to mention that it is not feasible to source 100% debt funding for any scheme from the market. The power sector loans are already facing a slew of problems due to high non-performing assets. In the present economic scenario, Banks/Financial institutions are reducing their power sector exposure. When the banks are reluctant to lend to power sector because of their exposure to stressed assets, 100% debt financing is neither possible nor practical.

Any additional capital expenditure incurred on projects is normally funded from both debt and equity. With regard to the implementation of the revised emission control norms, the cost of installation of Flue Gas Desulphurization (FGD) equipment is in the range of 30-70 lakhs per MW depending on unit size and configuration. Considering the overall portfolio of NTPC thermal plants where FGD

is required to be installed, the total capital investment requirement for installation of FGD equipment would be approximately Rs.26000 Crores. In addition the investment in the JV/ subsidiary companies of NTPC would be about Rs 7800 crores. If cost of De-NOx schemes of Combustion Modification and SCR/ SNCR is also included, the total expenditure towards ECS would be much higher for all NTPC stations (excluding JVs). With return on equity to be serviced at weighted average rate of loan, the generators would be forced infuse minimum equity or no equity. Sourcing such huge quantum of funds only in form of debt is not possible. In such case the cost of debt funding would increase and may defeat the very intention of lowering the tariff.

Further, even in the case of the large generating companies like NTPC, banks may be reluctant to sanction fresh loans, as the total loan amounts may breach RBI guidelines regarding norms of maximum exposure to single borrower.

Further, NTPC has a debt of about Rs. 1,70,000/- crores as on 31.03.2020, which will increase in future due to large capex programs to meet environmental regulations, investments in RE projects, capacity expansions through organic and inorganic growth, etc.

Loan covenants in case of most of the long term debt instruments, through which NTPC has raised money, stipulate maintaining a specified maximum Debt to EBITDA ratio. **With reduction in returns and increase in debt, all other things remaining constant, the ratio, is likely to shoot up and breach the covenant, triggering recall/renegotiation of the existing loans by lenders.**

Therefore, it is neither practicable for generator to take loans nor possible for lenders to lend 100% credit to generating companies, for implementation of ECS.

1.5 No Incentive to generator for refinancing of loan

Further, under this approach, the generators would have no incentive for re-financing of loan from cheaper sources. It may be pertinent to mention that NTPC had passed on huge benefits by re-financing of loans in some stations during the tariff period 2014-19. This has been indicated in the various true-up petitions filed for the period 2014-19 in respect of these stations. With allowing Return on Equity at the weighted average rate of interest of loan of station/ company, the generator may not opt for re-financing of loans, as the same would decrease the return on equity (RoE) and reduce the profitability of the station/ company.

1.6 Disparity in returns where ECS is part of original investment approval vs ECS at stations under MoEF notification

Moreover, in stations such as Bongaigaon and Vindhyachal Stage-V, where ECS is a part of the Feasibility Report (FR), equity invested towards the same shall be serviced @ 15.5% whereas equity invested in ECS at stations that fall under MoEF notification dated 07.12.2015 shall d be serviced at debt rate as per the proposed amendment to the Regulations. This would create a disparity between these stations and would be inequitable.

1.7 Adverse impact on generation tariff:

The intention / objective of the proposed dispensation seems to be probably to lower generation tariff by servicing add-cap at interest rate on loan, may not ultimately deliver the desired benefit. Increase in debt financing or 100% debt financing shall increase the rate of interest on loan as the risk perception of lenders shall increase. This would affect all future loans and shall actually result in tariff increase which may nullify the intended benefit of lowering the tariff.

1.8 Reluctance of banks to advance loans for ECS

In a recent order dated 23rd April 2020, seeking in principle approval for installation of ECS by Sasan Power Ltd(SPL), it is mentioned by SPL that lenders are not willing to lend money unless the same is approved in-principle by Hon'ble Commission.

Further it has been mentioned in the aforesaid order that the Ministry of Power vide its letter dated 20.04.2020 addressed to the Secretary of the Commission, has stated as under:

"It was observed that CERC was also contemplating to amend the Tariff Regulations 2019-24 to provide for norms for installation of FGDS for complying with the environmental operating norms as Change in Law.

2. In the above mentioned meeting held on 09.04.2020, it was recommended that in view of the stipulated timelines decided by the Hon'ble Supreme Court for installation of FGDs, investment approval may be accorded by CERC at the earliest possible on applications of FGDS submitted by Genco's based on the CEA's benchmark cost and indicative technologies so as to facilitate funding of banks/ FIs. It was also felt that upon completion of the installation of FGD or a month before the completion of installation, the applications for fixation/revision of tariff may be filed and CERC would, as far as possible, dispose them in a time frame of 3 months so that the Genco's are not cash strapped and ***the lenders feel assured****."*

From the above, it appears that banks may be reluctant to fund for installation of ECS unless the investment proposals receive in principle approval by the Hon'ble Commission and the lenders are assured of debt servicing by the generators.

1.9 Adverse impact on financial ratios leading to financing problems

With such huge capex through debt, there will be adverse impact on solvency ratios and profitability ratios of the company e.g. Debt to EBITDA ratio will shoot up, which will adversely affect the borrowing capacity of company.

As stated above, loan covenants in case of most of the long-term debt instruments, through which NTPC has raised money, stipulate maintaining a maximum Debt to EBITDA ratio of 6.50. With reduction in returns and increase in debt, all other things remaining constant, the ratio, is likely to shoot up and breach the covenant, triggering recall/renegotiation of the existing loans by lenders. NTPC's credit ratings would be severely impacted increasing the cost of borrowings.

Further, entire capex to the tune of Rs.30,000 Cr is to be incurred by FY 2021-22 so that deadlines prescribed to new emission norms could be met.

To illustrate the impact of the proposed amendment to the regulations, it is submitted that considering the weighted average rate of interest on loan as 8% and Loan outstanding on the company of about Rs 1,70,000 Crores, any adverse effect on solvency ratio leading to credit rating of company changing from AAA to AA would lead to an increase of about 0.5% in borrowing rate. Due to this incremental interest rate, company would have to pay additional Rs. 850 crores as interest which shall be recovered through tariff.

1.10 Works in the nature mandatory nature for general betterment

It may be appreciated that the works under change in law are mandatory in nature and are required to be necessarily carried out by the generating Company in compliance to the directions of courts, government instrumentality, etc. These

works under change in law are generally not related to day to day operations, but are in nature of general betterment of environment, safety, etc.

1.11 Different rates for different Companies for servicing additional capitalization:

The proposed dispensation shall result in different rates for servicing of equity invested in add-cap for different companies as per the weighted average actual interest of loan of that station/company. Govt. companies will get lower RoE on account of their lower borrowing cost when compared to private companies. Further, there is no incentive to the generating company to lower interest rate. As equity invested in ECS is proposed to be serviced at actual interest rate on loan, the proposed dispensation may provide perverse incentive to increase the rate of financing. The generating companies having higher financial efficiency like NTPC wouldearn lower returns while companies with relatively poor financial efficiency would earn higher returns, which would be against the intent of Regulations.

1.11 Other Submissions:

It is respectfully submitted that proposed provisions in the Draft First Amendment Regulations again provide that additional capital expenditure incurred on account of implementation of Emission Control System/Change in law by the generator will earn a return equal to interest on loan only with no premium on account of risk inherent in any equity investment.

It is submitted that all the other components of supplementary fixed charges are in nature of reimbursement of cost involved only and there would be no return available to the Company for risks in investments and efforts involved in the implementation of ECS systems as detailed below:

Sl. No.	Particulars	Proposed Amendment	Comments
1	Debt Equity Ratio	70:30	Equity ratio 30% maintained in line with Tariff Reg 2019
2	**Components of Supplementary Capacity Charges**		
	Return on Equity	*Shall be computed at the* ***weighted average rate of interest*** *on actual loan portfolio of the generating station*	***The return allowed on equityinvestment is an opportunity cost of investment which could have earned pre-tax 15.5%, even if applied in any other project of the Company. It is submitted that ROE, which by definition has to include a risk-premium, cannot be equated with interest on debt, which is a fixed income instrument.***
	Interest on Loan Capital	The rate of interest at the weighted average rate of interest of actual loan portfolio of the emission control system	Actual cost of debt incurred has been allowed to be recovered through Tariff
	Depreciation	From the date of operation **for the balance useful life or extended life of the generating station**, as the case may be	Capital cost allowed to be recovered through depreciation over balance useful life. For stations where useful life has been completed or is on the verge of completion, the issue

			has been further discussed in our comments
	O&M Expenses	**2% of the admitted capital expenditure (excluding IDC & IEDC)** as on the date of its operation, escalated annually @ 3.5%. Income generated from sale of gypsum or other by-products shall be reduced from the operation & maintenance expenses.	Allowed on Normative basis. Actual O&M may exceed the norms. Besides no extra overhead expenses have been proposed to be allowed to the Generator to handle gypsum. This issue has been further discussed at in our comments.
	Int. on Working Capital	Norms same as applicable to generating stationsexcept Advance payment for 30 days *towards cost of limestone or Reagent for generation corresponding to NAPAF not included in Working Capital*	Norms of Working capital allowed in line with generating station except Advance payment for 30 days *towards cost of limestone or Reagent for generation corresponding to NAPAF , which has not been specifically included, perhaps due to oversight, in Working Capital*

As may be observed from the above, no return would be available to the Company in any of the component of the Supplementary Capacity Charges.

It is further submitted that returns have to be commensurate to the risks involved in any capital expenditure. Also the availability of the ECS would also effect the availability of the unit increasing the machine availability. In case of lower availability of station than the normative Availability, the station would not get full fixed charges. Therefore this investment carries risk but without any return. Servicing of equity at debt rate is not justified, with so much risk involved in power sector and the stringent regulations for recovery of tariff.

Further, the additional capitalization is carried out either to meet certain legal obligations or for successful and efficient operation of the system. Therefore, all such expenditure is an investment towards asset creation and such investments should be allowed to earn a fair rate of return.

In view of the above, it is submitted that additional capitalization on account of change in law including ECS funded with equity should continue to be serviced at rate of return on equity of 15.5%. This will be in the larger interest of all the stakeholders, i.e. Generators, DISCOMS and lenders. According, it is submitted that the proposed amendment in Regulation 30 may not be considered for implementation.

2. ***2. Amendment to Regulation 3 of the Principal Regulations***

2.2. A new clause, namely, Clause (15a) shall be inserted after clause (15) of Regulation 3 of the Principal Regulations as under:

"(15a) 'Date of Operation' or 'ODe' *in respect of an emission control system means the date of putting the emission control system into use after meeting all applicable technical and environmental standards, certified through theManagement Certificate duly signed by an authorised person, not below the level of Director of the generating company;"*

2.3 A new clause, namely, Clause (20a) shall be inserted after Clause (20) of Regulation 3 of the Principal Regulations as under:

*"(20a) "**emission control system**" means a set of equipment or devices required to be implemented in the coal or lignite based thermal generating station to meet the revised emission standards;"*

3. ***4. Amendment to Regulation 9 of the Principal Regulations***

4.1. A new proviso, namely, Fourth Proviso shall be added to Clause (1) of Regulation 9 of the Principal Regulations as under:

4 "Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in the coal or lignite based thermal generating station in accordance with these regulations not later than 60 days from the date of operation of such emission control system."

4. ***8. Amendment of Regulation 18 of the Principal Regulations**:*

8.1. A new clause, namely Clause (6) shall be added after Clause (5) of Regulation 18 of the Principal Regulations as under:

"(6) Any expenditure incurred for the emission control system during the tariff period as may be admitted by the Commission as additional capital expenditure for determination of supplementary tariff, shall be serviced in the manner specified in clause (1) of this Regulation."

2. **Comment:**

2.1 It may be pertinent to mention that installation of ECS in all units of a station would involve meticulous planning involving consultation of all stakeholders as all units have to be taken under shut down one by one for installation and commissioning of the ECS in each of the units. Taking units under shut down would depend upon many factors like grid demand, availability of other units/ generators on bar, seasonal variations etc. Accordingly, putting the emission control system into use after meeting all applicable technical and environmental standards in all units one by one would take considerable time in a station particularly those having a many units, , such as Singrauli –I&II (7 units), Korba-1&2 (06 units), etc.

2.2 Considering an interval of three months between commissioning of emission control system between successive units of a multi-unit station , it would take about 1.5 year (average) for completion of all ECS schemes in all units of a station depending upon number of units in a station and permission given for shutdown of different units which in-turn depend upon on various factors including the grid condition.

2.3 such being the case, as per the proposed provisions, the generator can make an application for determination of supplementary tariff only 1.5 years after commissioning of ECS scheme in 1st Unit and thereafter about 2-3 months would be further required for determination of tariff by Hon'ble Commission. During the period from installation of ECS in first unit till determination of tariff by the Hon'ble Commission i.e. about 02 years (on an average) the generator would continue to incur operating expenditure towards operation of the ECS of unit(s)/ station. The additional opex pertaining to ECS would include reagent cost, maintenance cost, manpower/ employee cost, consumption of spares, water charges, etc. while there would be no corresponding revenue stream available for the generator till the tariff is determined by the Hon'ble Commission. In such case the generator shall face liquidity issues due to lack of cash flow.

2.4 Accordingly, it may be prudent that the generator may be allowed to make an application for determination of Supplementary Tariff based on estimated expenditure from the date of anticipated completion of ECS in 1st Unit and on projected expenditure basis for balance schemes in remaining units, subject to true-up, as per the existing practice being allowed in the case of determination of tariff for units/ station on anticipated basis in line with the provisions of the CERC Tariff Regulations, 2019. Further, generators may be allowed to bill the supplementary tariff provisionally based on the petition/application submitted before the Hon'ble Commission till tariff determination by Hon'ble Commission so that generator could sustain his operations based on the revenue stream in respect of ECS. This would also be in tune with the MOP letter dated 20.04.2020 mentioned above.

2.5 Further, extending 4th proviso to clause 1 of Regulation 9, for tariff filing of ECS, it can be inferred that ECS petition can be filed on commissioning of ECS in generating station or unit thereof.

2.6 In view of above, it is suggested following changes may be considered in respect of above proposed amendments.

1) A phrase “in a unit/ station” may be introduced between the words ‘system’ and ‘means’ in the first line of the proposed definition of “Date of operation or Ode” in Clause (15a) of Regulation 3,
2) Similarly, words “generating station” may be substituted with “generating unit/ station as the case may be” in the proposed clause (20a) of the Regulation 3
3) Fourth Proviso proposed to be added to Clause (1) of Regulation 9 so as to enable generator to make an application before Hon’ble Commission within 60 days from the anticipated date of operation of ECS. Provision for true-up of the ECS expenditure during the control period may also be introduced in Regulation 9
4) Words ”or projected to be incurred” may be inserted after the word ‘incurred’ and before the word ‘for’ in the proposed new clause (6) of Regulation 18

5. ***2. Amendment to Regulation 3 of the Principal Regulations:***

2.1. A new clause, namely, Clause (6a) shall be inserted after clause (6)of Regulation 3 of the Principal Regulations as under:

“(5a) ***Auxiliary energy consumption for emission control system ' or 'AUXe'*** *in relation to a period in case of coal or lignite based thermal generating station means* ***the quantum of energy consumed by auxiliary equipment of the emission control system*** *of the coal or lignite based thermal generating station”*

3.0 Comment:

The draft Amendment has proposed that "A new clause, namely, Clause (6a) shall be inserted after clause (6)" It is suggested that it should read as " A new clause, namely, Clause (5a) shall be inserted after clause (5)"

3.1 Flue-gas desulfurization (**FGD**) is installed between the Electrostatic Precipitator (ESP) and the Induced Draft (ID) fan to reduce SOx emission from the Power Plant Boilers. The installation of FGD equipments in the flue-gas path increases the flue-gas path resistance and therefore requires increased draft power of ID Fans to maintain the required negative furnace pressure in the Boiler furnace. The requirement of increased draft power is generally met by increasing the draft power through two configuration modes in thermal power plants. One is to install booster fan along with the FGD equipments. This configuration is implemented in cases where the FGD is retrofitted into the existing operational units/ station. The other configuration does not employ the use of booster fan; instead a bigger/ higher rating ID fan is installed which can maintain the required pressure in the whole boiler system. This integrated configuration is followed where FGD is conceived in original scope of work and incorporated into the system during the design of the power plant.

3.2 As per the proposed definition of auxiliary energy consumption for ECS, the increase in quantum of energy consumption by Booster Fans is covered as it forms part of auxiliary equipment of FGD. However the increased energy consumption by bigger ID Fans in the integrated model would not be included as per the above definition. For example, the ID Fan rating of Bongaigaon TPS (3x250MW) is about 3.6 MW each whereas in case of BRBCL (4x250 MW) the ID Fan rating is about 1.8 MW each. This is due the fact that in case of Bongaigaon TPS, FGD was envisaged in the original scope of work and by design ID fan power rating was increased to avoid the requirement of Booster Fan, whereas in case of BRBCL, FGD is retrofitted. As such extra auxiliary consumption due to installation of ID fan of higher rating at Bongaigaon may not be covered in the above definition. Accordingly, the increased energy consumption by bigger ID Fans need to be considered additionally.

3.3 In terms of above, installation/ operation of equipments/ systems of emission control system (ECS) to meet new emission norms may affect the energy consumption of other equipments already installed for generation of electricity in the plant.. Accordingly, Aux power for ECS system should not be measured separately as some equipment may be common. In view of above Normative Aux power should be combined i.e. aux power of main plant + aux power of ECS and additional APC on normative basis to be allowed.

6. ***3. Amendment of Regulation 8 of the Principal Regulations***

3.1. In Clause (1) of Regulation 8 of the Principal Regulations, the words"including emission control system, wherever applicable," shall be inserted in first line after the words "generating station" and before the words "may be";

3.2. In Clause (4) of Regulation 8 of the Principal Regulations, the words "on submission of the completion certificate by the Board of the generating company" shall be substituted by the words "in accordance with the application filed under 4th proviso to clause (1) of Regulation 9 of these regulations."

Comment: The tariff in respect of ECS is being determined separately by the Hon'ble Commission as supplementary tariff in respect of a station, accordingly it is suggested that the word "including" may be replaced by "and".

7. ***6. Amendment of Regulation 15 of the Principal Regulations.***

6.1. The existing clause of Regulation 15 of the Principal Regulations shall be re-numbered as Clause (1).

6.2. In re-numbered Clause (1) of Regulation 15 of the Principal Regulations, the words "based on capital cost," shall be inserted after the words "communication system".

6.3. A new Clause, namely Clause (2) shall be added after there-numbered Clause (1) of Regulation 15 of the Principal Regulations as under:
*"(2) **Supplementary Capacity Charges:** Supplementary capacity charges shall be derived on the basis of the Annual Fixed Cost for emission control system (AFCe). The Annual Fixed Cost for the emission control system based on capital cost shall consist of the components as listed at (a) to (e) of Clause (1) of this Regulation."*

Comment: Normative O&M Expenses (in lakh/ MW) allowed under Regulation 35 (1) of Tariff Regulations 2019 in respect of thermal generating unit/ station are derived based on the past actual O&M expenses and are independent of the capital cost of the unit/ station. These normative O&M expenses based on the unit size and type are allowed as part of Annual Fixed Charges. Similarly, special allowance allowed under Regulation 28 as part of AFC for units / stations for carrying out R&M of units are also independent of capital cost.

In view of the above, it is suggested that the phrase "based on capital cost" may not be be required to be added in the Regulation 15 (1)

8. ***11. Amendment of Regulation 29 of the Principal Regulations***
11.1. A new clause, namely, Clause (5) shall be added after Clause (4) of Regulation 29 of the Principal Regulations as under:
"(5) Un-discharged liability, if any, on account of emission control system shall be allowed as additional capitalization during the year it is discharged, subject to prudence check."

Comment: It is submitted that during the installation of ECS in a unit/ station there are certain works/ expenditure which are carried out even after commissioning of ECS i.e. even after the systems are put in use. These works/ expenditures may include release

of balance payments at the time of contract closing, balance works under original scope, capitalization of initial spares pertaining to ECS, etc. Further, certain works may be necessitated to be carried out for successful operation of the ECS due to site specific conditions for sustained and reliable operation of ECS. Accordingly, word "Deferred works, in the original scope of work along with" may be added before Un-discharge liability, in proposed clause (5) of regulation 29.

9. ***14. Amendment of Regulation 33 of the Principal Regulations***

14.1. A new clause, namely, Clause (9) shall be added after Clause (8) of Regulation 33 of the Principal Regulations as under:

"(9) The depreciation of the emission control system shall be computed from its date of operation for the balance useful life or extended life of the generating station, as the case may be."

Comment: It may be pertinent to mention that in order to comply with the MoEF notification dated 07.12.2015, NTPC is installing ECS in all its stations including stations which have completed their useful life or are at the fag end of their useful life .In order to remove ambiguity and to ensure recovery of the depreciation of ECS in a phased manner, it is suggested that depreciation may be allowed to be recovered in 5 years where the balance useful life of the station is less than 5 years.

10. ***15. Amendment of Regulation 34 of the Principal Regulations***

15.1. A new clause, namely, Clause (aa) shall be inserted after Clause (a) of Regulation 34 of the Principal Regulations as under:

"(aa) For emission control system of coal or lignite based thermal generating stations:

(i) Cost of limestone or reagent towards stock for 20 days corresponding to the normative annual plant availability factor;

(ii) Receivables equivalent to 45 days of supplementary capacity charge and supplementary energy charge for sale of electricity calculated on the normative annual plant availability factor;

(iii) Operation and maintenance expenses in respect of emission control system for one month;

(iv) Maintenance spares @ 20% of operation and maintenance expenses in respect of emission control system."

Comment: It may be appreciated that Generator would be incurring expenditure on account of consumption of reagents/ lime corresponding to one month's generation which would be billed in the following month. In this regard the generator would incur substantial expenditure towards the cost of reagent that would be consumed corresponding to one-month's generation. As the same would be recoverable only after 45days to 50days from the day of billing , the generator would have to meet such expenditure by taking short term working capital loans. In addition to the normal usage, sufficient stock would also be required to be maintained to meet sudden disruptions in supply of lime/ reagent due to exigencies such as strike, floods etc. Accordingly, cost towards expenditure in respect of consumption of reagents corresponding to one-month's generation at normative level may be allowed to the generator as is permitted in case of fuel.

In view of above, the generator would incur substantial expenditure towards consumption of lime/ reagent towards one-month's generation and towards stock. Accordingly, it is suggested that a new sub clause for consumption of reagent/ lime for one-month's generation may be introduced as being allowed in the case of coal.

11. ***16. Amendment of Regulation 35 of the Principal Regulations***

16.1. At the end of the first sentence of first proviso under sub-Clause (6) of Clause (1) of Regulation 35 of the Principal Regulations, the words "and considering the norms of specific water consumption notified by the Ministry of Environment, Forest and Climate Change" shall be added.

16.2. Sub-Clause (7) of Clause (1) of Regulation 35 of the Principal Regulations along with its proviso shall be substituted as under:

"(7) The operation and maintenance expenses on account of emission control system in coal or lignite based thermal generating station shall be 2% of the admitted capital expenditure (excluding IDC & IEDC) as on the date of its operation, which shall be escalated annually at the rate of 3.5% during the tariff period ending on 31st March 2024:

Provided that income generated from sale of gypsum or other by-products shall be reduced from the operation & maintenance expenses."

Comment:

O&M Expenses : It is submitted that, the ECS technologies like FGD, SCR/ SNCR are in nascent stages and yet to evolve, stabilize and mature in India. There is dearth ofadequate repair and maintenance know-how of these new technologies& systems and availability of specialized vendors other than OEM would take some time. Accordingly, the cost of O&M during the initial years of operation is expected to be high. In this regard it would be prudent to considerhigher O&M expenses in the initial period so that the systems could be operated on sustained basis

It may be noted that in FGD/ De-NOx systems,as substantial amount of concentrated chemicals are used/ handled, equipments of the ECS are relatively more prone to chemical corrosion and need frequent maintenance and replacement of rubber linings etc. Also,other chemical protective measures are required to be carried out frequently. Accordingly, the O&M expenditure are expected to be higher in the ECS systems,

In view of above the O&M expenses may be allowed at the rate of 4% of the capital cost with an escalation of 3.5% year on year basis. The same may be reviewed at the end of 03 years at the time of true-up based on actual expenses.

Sale of Gypsum or other by-products: Further it has been provided in the draft regulation thatany revenue generated from sale of gypsum and other by-products would be utilized to set-off O&M expenditure. In may be appreciated that the generator would incur substantial expenditure towardshandling and maintenance of requisite facilities,development of market / vendors and facilitation for sale of gypsum or other by-products as per the demand and quality.

The proposed regulation does not provide any incentive for the generators to make efforts to increase the revenue from the sale of gypsum., In view of above,it is submitted to incentivize the generator to maximize the revenue generation from sale of gypsum or other by products by enabling provision of sharing the income from sale of gypsum in the ratio of 50:50 with the beneficiaries in line with the provisions of Tariff Regulations in regard to income from sale of scrap, etc.

Specific Water consumption:

Specific Water consumption (Liters/kWh) of thermal power stations increases with reduction of Plant loadfactor (PLF). This is because in a power plant when the generation decreases, water consumption does notdecrease in the same proportion.

A power station operating at low PLF would still require certain minimum quantity of water to meet theoperating requirements such as Equipment cooling water, Fire service, Cycle make-up, ash handlingsystems, Dust suppression systems etc. Accordingly, the specific water requirement in power plantsoperating at low PLF would be higher than those operating at higher PLF.

Accordingly the words “and considering the norms of specific water consumption notified by the Ministryof Environment, Forest and Climate Change with appropriate relaxation in cases of low PLF” may be incorporated.

23. Amendment of Regulation 43 of the Principal Regulations

23. Amendment of Regulation 43 of the Principal Regulations

23.1. At the end of the title heading of Regulation 43 of the Principal Regulations, the words "and Supplementary Energy Charge for Coal or Lignite based Thermal Generating Stations:" shall be added.

23.2. In Clause (2) of Regulation 43 of the Principal Regulations, the words "and Supplementary Energy charge rate" shall be added after the words "Energy charge rate (ECR)"

23.3. The words "ECR" shall be inserted at the beginning of the title heading of sub-clause (a) of clause (2) of Regulation 43 of the Principal Regulations

23.4. A new sub-clause, namely, sub-clause (aa) shall be inserted after sub-clause(a) of clause (2) of Regulation 43 of the Principal Regulations as under:

"(aa) Supplementary ECR for coal and lignite based thermal generating stations:

Supplementary ECR = (□ECR) + (SRC x LPR / 1000)

Where,

(□ECR) =Difference between ECR with revised auxiliary consumption with emission control system equivalent to (AUXn + AUX en) and ECR with normative auxiliary consumption as specified in these regulations and revised;

SRC = Specific reagent consumption on account of revised emission standard (in gm /kWh);

LPR = Weighted average landed price of reagent for emission control system (in Rs/kg)".

Comment: It may be pertinent to mention that due to installation of De-NOx technologies such as Combustion Modification and SCR/ SNCR there would be deterioration in the unit heat rate.

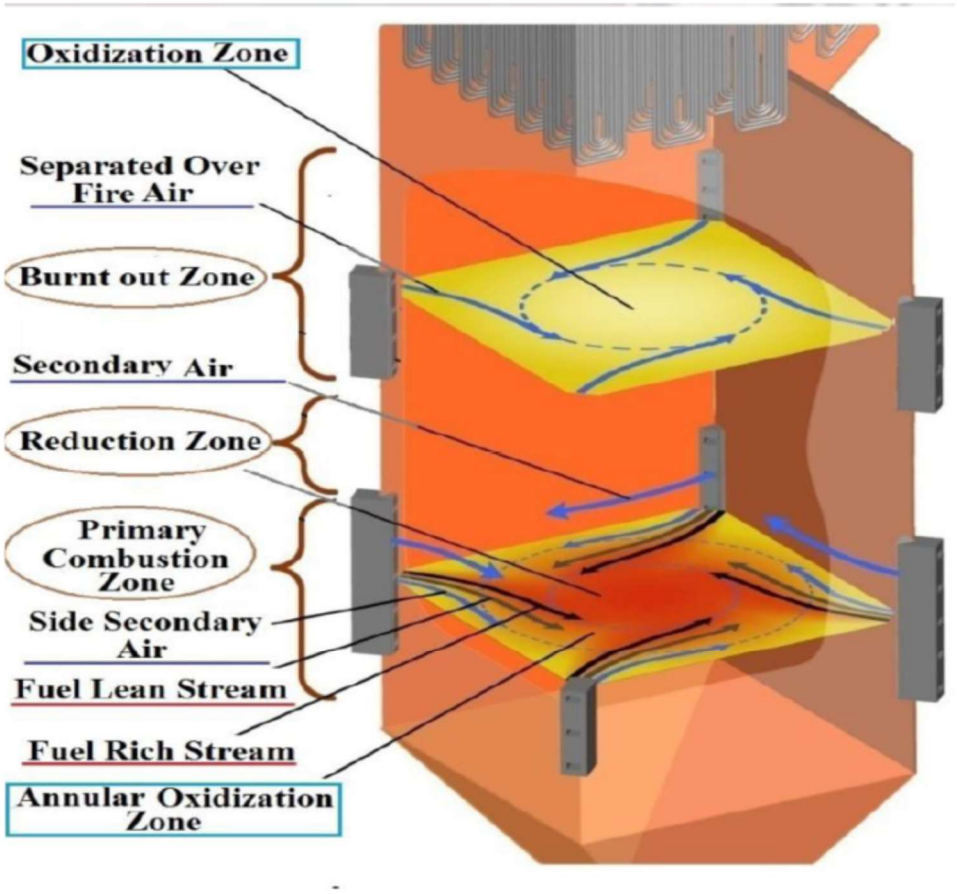
In this regard it is submitted that NOx control technologies can be broadly divided into two main categories:

Primary or combustion measures and Secondary or flue gas controlsystems. The rates of NOx reduction and the costs vary considerably.They can be used alone or in combination, depending on the level of NOxreduction required.

1. Primary measures i.e. Combustion Modification & Tuning

Primary measures—including Low NOx Burners (LNBs), Over fire Air (OFA), lower excess air and combustion optimization in boiler are the cheapest and most economical approach available to obtain an initial reduction in NOx emissions for any coal-fired plant.

By controlling coal combustion conditions, such as, the flame temperature, excess air and fuel residence time in boilers, they reduce NOx emissions. However, combustion modification in existing boilers can affect boiler operation and lead to increased levels of Carbon-monoxide (CO), and more unburnt carbon in the ash. Burner flame geometry also changes and the flames can impinge on the furnace water walls. In India, mostly boilers have burners that are of tilting tangential type, have closed coupled OFA and are supplied by the BHEL (Bharat Heavy Electricals Limited). Combustion modification is being done in these boilers and will be retrofitted during the next outages.



Combustion Modification-Burner Modifications and Combustion Optimisation

Burner modifications usually take the form of reduced burner throat diameter (in case of wall fired boilers), or reduced secondary area nozzle area (in case of tangentially fired boilers), in order to maintain wind-box pressure and secondary air velocity when a large amount of air is diverted from the wind-box to OFA systems.

Together with Combustion Optimization which would allow a further reduction in totalcombustion air flow, an increase in staging with OFA for NOx reduction and improveduniformity of air flow among the burners. It is expected that burner modifications andcombustion optimization may result in achieving NOx reduction between 10% and 40%. HigherNOx reduction levels could be achieved, depending on the baseline boiler

operationconditions and the capacity of OFA design being achieved prior to optimization and burnerreplacement with Low-NOx Burners

Prior to the requirements for NOx reduction, coal-fired burner was predominantly designed to achieve maximum combustion efficiency through rapid mixing of fuel and air in the combustion zone, resulting in low levels of CO and LOI. However, rapid mixing of fuel and air promoted high levels of NOx, typically in the order of 800-1000mg/Nm3.

Later when NOx reduction was required, the low NOx burner was developed, based on the principle of staging the mixing of fuel and air through burner designs. So, in cases where low-staging based combustion technology is in use, the more cost-effective option is to replace and retrofit with low NOx burners and Over-fire air (OFA) system.

An OFA system diverts a portion of combustion air from the burner wind-box to air ports located above the burner zone. Typical OFA air flow is designed to be 15%-20% oftotal combustion air, which results in 15%-30% NOx reduction alone or 25%-35% NOx reduction when combined with Low Nox burners (LNB), from baseline emissions. For a tangential-fired furnace, usually two levels of closed-coupled OFA (CCOFA) ports are assembled with burners through the same windbox at each corner. In addition, a separated OFA (SOFA) port may be installed at a higher furnace elevation and at each corner of the furnace. In this case a portion of combustion air is also diverted from the wind-box to SOFA ports through air ductwork. For a wall-fired furnace, OFA ports are installed above the burner zone on either the front wall only or on front and rear walls. Again, a proportion of combustion air is diverted from the wind-box to OFA ports through air duct work.

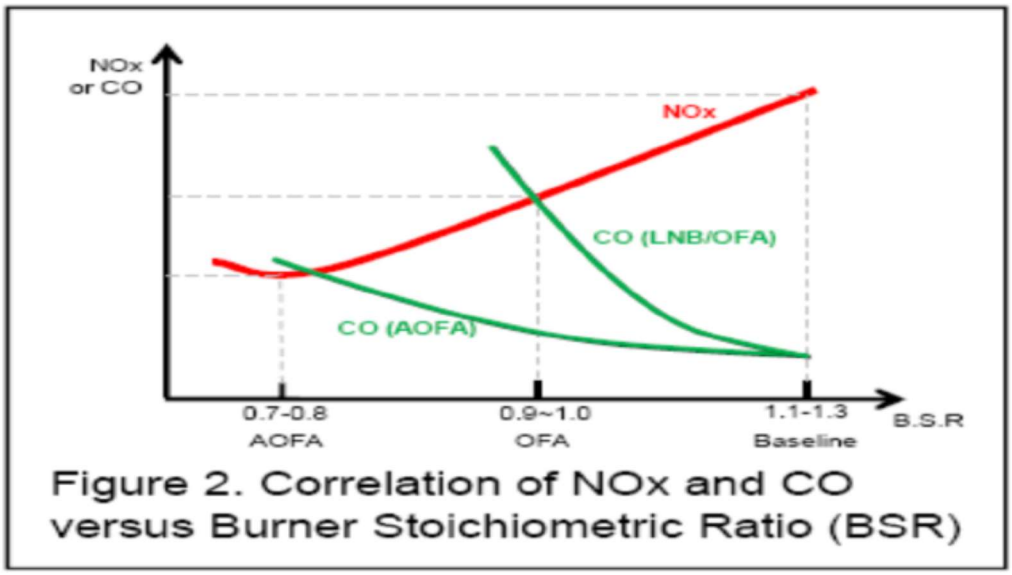


Figure 2. Correlation of NOx and CO versus Burner Stoichiometric Ratio (BSR)

In view of above, there would be increase in un-burnt loss which would lead to deterioration of unit heat rate.

2. Secondary Measures i.e. SCR/ SNCR

In secondary measure for removal of NOx, i.e., Selective non-catalytic reduction (SNCR) and Selective catalytic reduction (SCR) process involves injecting nitrogen-containing chemicalsinto the boiler within a specific temperature window. There are different chemicals which can be usedthat selectively react with NOx in the presence of oxygen to form molecular nitrogen and water, but the two most common chemicals are ammonia/ urea. Due to formation of water particles during NOx reduction, it increases the wet loss of boilers leading to deterioration of Unit Heat Rate by about 0.4%.

In regard to the above discussions, typical heat loss in a 500 MW unit due to Primary and Secondary NOx removal system is tabulated below:

A. Typical efficiency loss for SNCR

	Vendor-1	Vendor-2	
Water consumption	6000	10000	Kg/Hr
Coal consumption	330	330	T/hr
enthalpy at 140 deg c	2764	2764	kj/kg
enthalpy at 35 deg c	167	167	kj/kg
heat loss	11.28	18.80	kcal/kg of coal
% of heat loss	**0.3**	**0.6**	

B. SCR sensible Heat Loss

Ash temperature	340	Deg C
% of ash	8	%
Specific Heat of Ash	0.201	kcal/kg
Coal Fired	330	T/hr
Ash in coal	45	%
Total Ash	148.5	
Heat loss in ash	704424.6	Kcal/Hr

Per Kg of Coal	2.13462	Kcal/Kg of Coal
% loss in efficiency	0.1	%

C. Combustion Modification

Increase in un-burnt carbon loss	0.7	%
Total coal fired for 500MW	330	Ton
Ash in Coal	42	%
GCV of coal	3300	Kcal/Kg
Total ash in 500 Mw	138.6	T/hr
Total Carbon	0.9702	T/hr
Total Heat loss for 500MW	8498.952	Kcal/Hr
Total Heat Per KG of coal	25.7544	Kcal/Kg of coal
% Heat loss	0.8	% loss

It is clear from above that there would be heat loss in the range of 0.9% to 1.4% attributable to De-NOx systems.

In view of above, it is suggested that the differential ECR needs to be considered as difference of ECR with revised auxiliary consumption and revised station heat rate with emission control system and ECR with normative auxiliary consumption and normative station heat rate.

Further, the cost of lime/ reagent allowed in the supplementary ECR by the expression (SCR x LPR/ 1000) is equivalent to cost of reagent consumed corresponding to generation at generator terminals, however the same needs to be computed at ex-bus. Therefore, it is suggested that the expression (SCR x LPR/ 1000) needs to divided by the expression (1-AUXn-AUXen).

12. ***25. Amendments of Regulation 49 of the Principal Regulations***

25.1. A new sub-clause, namely, sub-clause (bb) shall be inserted after sub-clause (b) of Clause (E) of Regulation 49 of the Principal Regulations as under:

"(bb) Auxiliary Energy Consumption (AUXe) on account of emission control system of thermal generating stations:

Name of Technology		AUX_{en} (as % of gross generation)
(1) For reduction of emission of sulphur dioxide:		
a)	Wet Limestone based FGD system (without Gas to Gas heater)	1.0%
b)	Lime Spray Dryer or Semi dry FGD System	1.0%
c)	Dry Sorbent Injection System (using Sodium bicarbonate)	NIL
d)	For CFBC Power plant (furnace injection)	NIL
e)	Sea Water based FGD system (without Gas to Gas heater)	0.7%
(2) For reduction of emission of oxide of nitrogen :		
a)	Selective Non-Catalytic Reduction system	NIL
b)	Selective Catalytic Reduction system	0.2%

Provided that where the technology is installed with Gas to Gas heater, auxiliary energy consumption specified as above shall be increased by 0.3% of gross generation."

Comments:

i) In case of Dry Sorbent Injection (DSI) system for De-SOx, the additional APC allowed on normative basis indicated is "Nil". In this regard, it is submitted that in case of DSI system, a minimum 300-500 KW auxiliary power is required to operate the equipment of DSI system in a Unit size of 30 MW – 200 MW.Accordingly, an additional APC of 500 KW may be allowed for DSI system. Ash disposal cost may also be allowed in case ash is not saleable due to implementation of DSI.

ii) APC indicated is Nil for SNCR system, however it is expected in the range of 0.1-0.2%. This is based on pilot test conducted at two of the NTPC Stations. Accordingly, same may be allowed.

13. ***25.2. A new clause, namely Clause (F) shall be added after Clause (E) of Regulation 49 of the Principal Regulations as under:***

"(F) Norms for consumption of reagent: *(1) The normative consumption of specific reagent for various technologies for reduction of emission of Sulphur dioxide shall be as below:*

(a) For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: *The specific limestone consumption (g/kWh) shall be worked out by following formula:*

[0.85 x K x SHR x S]/[CVPF x LP]

Where,

S = Sulphur content in percentage,

LP = Limestone Purity in percentage,

SHR= Gross station heat rate, in kCal per kWh;

CVPF = (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal-based stations less 85 Kcal/Kg on account of variation during storage at generating station;

(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, based stations;

Provided that value of K shall be equivalent to (35.2 x Design SO2 Removal Efficiency/96%) for units to comply with SO2 emission norm of 100/200 mg/Nm3 or (26.8xDesign SO2 Removal Efficiency/73%) for units to comply with SO2 emission norm of 600 mg/Nm3;

Provided further that the limestone purity shall not be less than 85%.

(b) For Lime Spray Dryer or Semi-dry Flue Gas Desulphurisation (FGD) system: *The specific lime consumption shall be worked out based on minimum purity of lime (PL) as at 90% or more by applying formula [0.90x6 /PL(%)] gm/kWh;*

(c) For Dry Sorbent Injection System (using sodium bicarbonate): *The specific consumption of sodium bicarbonate shall be 12 gm per kWh at 100% purity.*

(d) For CFBC Technology (furnace injection) based generating station: *The specific limestone consumption for CFBC based generating station (furnace injection) at 85% purity limestone (kg/kWh) shall be computed with the following formula:*

[62.9 x S x SHR /CVPF] x [0.85/ LP]

Where

S= Sulphur content in percentage,

LP = Limestone Purity in percentage,

SHR= Gross station heat rate, in kCal per kWh,

CVPF = (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal-based stations less 85 Kcal/Kg on account of variation during storage at generating station;
(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, based stations;

*(e) **For Sea Water based Flue Gas Desulphurisation (FGD) system:** The reagent used is sea water, therefore there is no requirement for any normative formulae for consumption of reagent.*

(2) The normative consumption of specific reagent for various technologies for reduction of emission of oxide of nitrogen shall be as below:
***(a) For Selective Non-Catalytic Reduction (SNCR) System**: The specific urea Consumption of SNCR system shall be 1.2 gm per kWh at 100% purity of urea.*
***(b) For Selective Catalytic Reduction (SCR) System:** The specific ammonia consumption of SCR system shall be 0.6 gm per kWh at 100% purity of ammonia."*

Comments:

In reference to the proposed amendment at Clause (F) (a); it is submitted that the empirical formula indicated for calculation of specific limestone would require many inputs and would also require testing of Lime stone and coal. Practically this would be very difficult to implement. In view of above following may be considered for simplification of computing specific limestone consumption;

Option-1

In view of the same and simplify the process, it is suggested the formula suggested by CEA with 10% margin may be considered.

[1.1x K x SHR x S]/[CVPF] g/KWH
Where K -35.2 for units SO2 emission norm of 100/200 mg/Nm3 or 26.8 for units SO2 emission norm of 600 mg/Nm3;

(10% margin w.r.t. excess Limestone required w.r.t stoichiometric ratio)

Option-2

Normative Limestone consumption as per the table given below: -

% Sulphur	0.4	0.5	0.6	0.7	0.8	0.9
Lime stone Consumption with 10% Margin for 100/200 mg/NM3 (gm/KWH)	12	15	18	21	24	27
Lime stone Consumption with 10% Margin for 100.200 mg/NM3 (gm/KWH)	10	12	14	17	19	21

Following has been assumed for above

Assumption Average. GCV-3300 Kcal, 85 Kcal

Normative heat rate-2450 for 500 MW &above

Normative heat rate-2600 for below 500 MW

Detailed Calculation of same is enclosed at **Annexure-I**

In respect to the proposed amendment to clause (F)(c) above, it is submitted that the specific normative consumption of sodium Bi-carbonate is defined as 12 gms per KWH. . It is to be noted that Specific coal consumption t (per KWh) will vary based on the unit size. Since Heat rate varies according to unit size and configuration, it is suggested that accordingly the reagent consumption may be linked with heat rate or Specific coal requirement.

DSI technology is applicable for unit size below 500 MW.*As per CERC Regulations, normative* Heat rate*is specified according to the unit size.* Considering normative heat rate of 2450 kcal/kwh for 200/210 MW as the basis of working out the specific

consumption of sodium bi-carbonate whereby 12 g/KWH has been specified for 200/210 MW unit size, the reagent consumption works out to be 2750X12/2450=13.5 gm per kwh and 2870X12/2450=14.1 gm/KWh for 110 MW and 60 MW units respectively considering normative heat rate of 2750 kcal/kwh for 110 MW for Tanda & 2870 kcal/kwh for 60 MW for TTPS. Further, it is suggested that a margin may be allowed considering low effectiveness of DSI technology at lower unit size. Accordingly, it is suggested to modify reagent consumption as below:

a) for Unit Size ≥ 200 MW --12 g/KWh.

b) for Unit Size ≥ 100 MW and <200 MW–14 g/KWh.

c) for Unit Size <100 MW—15 g/KWh.

Further, 10% margin may be kept in above value as DSI implementation is being done for the first time for Indian coaland so there may be variation.

14. ***21. Amendment of Regulation 42 of the Principal Regulations***

21.1. In the proviso under the formula under Clause (2) of Regulation 42 of the Principal Regulations, the words "or installation of emission control system, as the case may be" shall be inserted after the words "Renovation and Modernisation".

21.2. Clause (5) of Regulation 42 of the Principal Regulations along with the proviso of the said clause shall be substituted as under: -

"(5) The Plant Availability Factor for a Month („PAFM") shall be computed in accordance with the following formula:

PAFM = 10000 x $DCi\,[NxICx\,100-AUXn-AUXen\,]$=1 %

Where,

AUXn = Normative auxiliary energy consumption in percentage;

AUXen =Normative auxiliary energy consumption for pollution control system as a percentage of gross energy generation, wherever applicable;

DCi = Average declared capacity (in ex-bus MW), for the ith day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch center after the day is over;

IC = Installed Capacity or (MW) of the generating station;

N = Number of days during the period;

Note: DCi and IC shall exclude the capacity of generating units not declared under commercial operation. In case of a change in IC during the concerned period, its average value shall be taken."

Comments: It may be noted that the generator has to take unit under shutdown for implementation of ECS in order to comply with the MOEF notification dated 07.12.2015. The generator is necessarily required to take shutdown to implement the MOEF Notification. Accordingly, it is requested to allow full AFC during shutdown for implementation of ECS at unit/ station.

It is further submitted that implementation of ECS cannot be compared with R&M activities. Generally, R&M is taken up after completion of useful life of the station by which time depreciation has been recovered. As against this implementation of ECS would be undertaken during the useful life of the station and therefore it is submitted that the generator should be allowed to recover the AFC for the period of shutdown needed to undertake works on account of the MOEF Notification.

15. ***9. Amendment of Regulation 21 of the Principal Regulations:***

9.1. In Clause (5) of Regulation 21 of the Principal Regulations, the words "either in entirety on in part" shall be substituted with the words "either in entirety or in part".

9.2. A new clause, namely, Clause (6) shall be added after Clause (5) of Regulation 21 of the Principal Regulations as under:

"(6) For the purpose of Clauses (4) and (5) of this Regulation, IDC on actual loan and normative loan infused shall be considered."

Comments: In order to bring clarity on admissibility of IDC on normative loan for the period of construction and for the delay period condoned, if any, as per the various orders of the Hon'ble Commission and Hon'ble ATE; the clause (6) above may be made applicable to Clauses (1) to (5) instead of clauses (4) and (5).

16. ***26.3. A new form namely, Form 16A shall be inserted after Form 16 of Annexure-I of Part I of the Principal Regulations.***

Comments: Loss of reagent/ lime during transportation may be allowed on normative basis so as to take care of loss of quantity and purity during handling and transportation as provided in case of coal. Accordingly, a row may be inserted in the Form-16 for the normative loss of reagent/ lime.

17. ***5. Amendment of Regulation 14 of the Principal Regulations:***

5.1. In Clause (2) of Regulation 8 of the Principal Regulations, the words "Supplementary capacity charges for additional capitalisation" shall be substituted with the words "Supplementary tariff consisting ofSupplementary capacity charges".

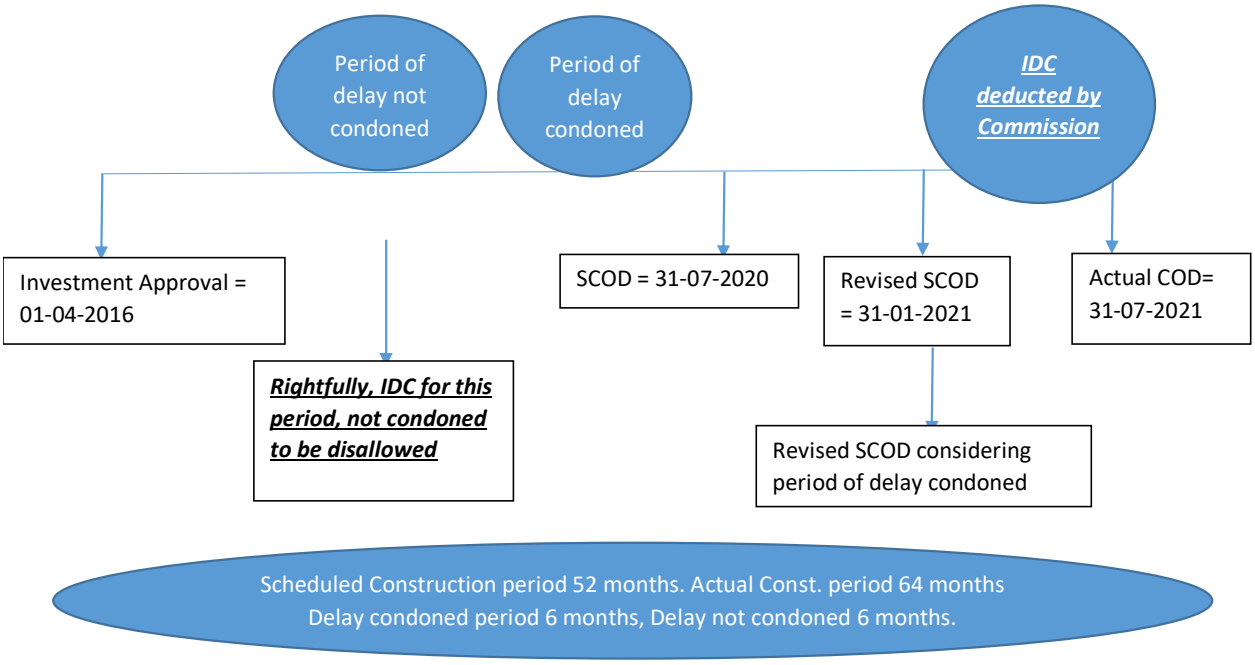
Comments:. It is submitted that there seems to be typographical error in the revised clause 5.1 and perhaps Clause(2) of Regulation 14 was intended to be referred to instead of Clause 2 of Regulation 8. The same may be clarified.

Additional Comments/ Views :

1. Treatment of IDC for the period not condoned during the project construction:

It is humbly submitted that presently Hon'ble Commission while computing the figure of Interest during Construction (IDC) disallowance for the period of delay not condoned, disallows the IDC accrued in the last months of the construction period, even if the delay is attributable to a specific period during construction which may occur during the start or in between at any time during the overall construction period.

As an example,if there is a delay in six months on account of controllable factors, IDC accrued during last 06 months of construction period is deducted. For clarity, this has been illustrated with the help of an example below:



It is submitted that this methodology is not equitable towards the generator, as IDC accrual in the last months is corresponding to the full capital cost, whereas the delay might have occurred at the beginning of the construction period or at some period in between the Investment approval date and the COD.

In this regard, it is may be pertinent to mention that if the project gets delayed during the initial or in between the period of execution, deployment of funds both debt and equity also gets deferred, due to deferment of the expenditure on the capital works. Accordingly, for the period of delay the IDC accrued is only for the debt already deployed prior to the delay. Whereas, if the IDC is deducted from the period just prior to tothe date of actual COD, the IDC disallowed corresponds to the total debt deployed till COD/ Re scheduled COD rather than the actual IDC accrued for debt deployed before the actual delay.

It is further submitted, the IDC corresponding to the un-condoned delay period/ month can be computed easily as IDC accrued during the project execution is submitted on quarterly basis along with the details of interest rates, funds phasing etc along with the tariff petition. Therefore, it is requested that IDC disallowed for the period not condoned due to controllable reasons may be considered equal to IDC accrued during the respective months/ periods when there was delay, for the actual period of delay not condoned.

2. SPECIFIC OIL CONSUMPTION FOR FRONT FIRED BOILERS and UNITS/ STATION WITH LOWER PLF:

Specific Oil Consumption (SoC) of a tangentially/ cornered boiler is a function of percentage unit loading and number of start-ups/ shut-downs. However, in case of front fired boilers, SoC is a function of percentage unit loading, number of start-ups/ shut-

downs and number of mill changeovers over a specified period. It may be appreciated that in day –to- day operations of units in both type of boilers i.e. tangentially fired and front fired boilers, mill changeover is a daily phenomenon. This changeover is done for operational reasons and for maintenance requirements of mills due to regular wear and tear of mill parts during coal pulverizing process. Due to this, Designer/ OEM provides for minimum 02 nos. of additional mills (for all unit sizes) i.e. one for daily maintenance and other available as hot-stand-by in case of emergencies/ break-down of running mills. Moreover, for a fuel to get ignited (catch fire); conditions for combustion in the form of appropriate temperature (ignition temperature) and oxygen is required. For safe burning of coal inside boilers during operation, certain checks and balances are built into the C&I logic system (permissive and protections) by OEM to avoid accidents due to insufficient ignition energy. One of such logic is the “ignition permit” that ensures providing ignition temperature for mill to be taken into service. It may be pertinent to mention that a mill becomes self-sustained after 50% loading, otherwise it needs continuous ignition temperature support from other supporting sources. In case of tangentially fired boiler the ignition temperature/ permit/ support is available from two sources i.e. (i) Adjacent self-sustaining mill in service and/ or (ii) from secondary oil support. However, in case of front fired boilers ignition temperature/ permit/ support is available from only one source i.e. from secondary oil support. Accordingly, every time a mill in a front fired boiler is taken in service oil support is required to taken as per design/ OEM specifications otherwise mill cannot be started. Further, oil support is required until the mill loading becomes adequate for self-sustaining. It may be appreciated that, mill changeover is a daily activity as all mills are to be taken for daily maintenance in rotation (one mill at a time for daily

maintenance). Similarly, oil support is also required for stopping the mill in order to avoid any unburnt pulverized coal being fired into the boiler. If oil support is not taken during stopping of mill ,there may be cases when fire ball of that elevation may get disturbed due to low load of mill. In view of above, it is required to take oil support for every mill changeover in case of wall fired boilers. Accordingly, specific oil consumption of the units having front fired boiler is more when compared to tangentially fired boilers. Farakka-II, Ramagundam-I and other new super critical units of NTPC such as Solapur, Lara, Kudgi etc. have front fired boilers . In this regard OEM provided documents/ logic diagrams is attached as **Annexure -II.**

It is further submitted that cost of oil as per the provisions of Tariff Regulations 2019 is linked with PLF/ scheduled generation of the Unit/ station as per specific oil norms at 85% loading. Hence units/ station having low PLF especially non-pit head stations and supercritical units with low PLF(less than 55%) units require upward revision in oil consumption norms.

It may be pertinent to mention that Oil compensation provided for start-ups more than 07 times in respect of stations/ units under RSD is based on fact that oil cost up to 07 start-ups for a unit is recovered though energy charges corresponding to scheduled PLF. However, units having low PLF (less than 55%) are not able to recover the cost of secondary fuel though energy charges and incur loss.

Accordingly, it is submitted that oil consumption in 7 start-ups is required to bemanaged with present specific oil consumption norms of 0.5 ml/kwhr. However, for units running with low PLF, these norms are quite less as detailed above.
For example, typically for a 660 MW unit, oil consumption allowed corresponding to one start-up as per prevailing norm of specific oil consumption of 0.5 ml/kwh is 1589 KL and 867 KLfor an operating PLF of 55% and 30% respectively. However, 07 start-ups in a year can be a combination of different type of start-up (Cold/Warm/hot) as per table below:

Cold Start-up	Warm Start-up	Hot Start-up	Average Oil Consumption
4	2	1	1880 KL
3	2	2	1550 KL
2	2	3	1330 KL

Considering average consumption of Cold/Warm/Hot-350 KL/150 KL/100 KL for a super critical units ofsizes (660/800 MW).

In view of above. It is suggested that additional Normative Specific Oil Consumption 0.5 ml/kwh may be allowed for front fired boilers over and above existing norms..

Annexure-I

Lime stone consumption

CEA Formula

Specific consumption of limestone =

$$\frac{K \times \text{Normative heat rate (kcal/kWh)} \times \text{Sulphur content of coal (\%)}}{\text{GCV of coal (kcal/kg)}} \text{ g/kWh}$$

Where,

K= 35.2 for units to comply with SO_2 emission norm of 100/ 200 mg/Nm^3.

= 26.8 for units to comply with SO_2 emission norm of 600 mg/Nm^3.

% Sulphur	0.4	0.5	0.6	0.7	0.8	0.9
Lime stone Consumption with 10% Margin for 100/200 mg/NM3 (gm/KWH)	12	15	18	21	24	27
Lime stone Consumption with 10% Margin for 100.200 mg/NM3 (gm/KWH)	10	12	14	17	19	21

Assumption Avr. GCV-3300 Kcal, Deduction of 95 Kcal as per CERC.

Normative heat rate-2450 for 500 MW & above

Normative heat rate-2600 for below 500 MW

10% margin for excess Limestone requirement wrt Stiometric ratio

4.1.4 Pulverized Coal Firing

The coal firing system is started stepwise one burner level after the other (one mill after the other) and is controlled or organized by the **Firing Sequence Control**. In this connection the starting programs of the respective coal mills are triggered. The relevant step sequences are described within the process description of the mills.

As a matter of principle the following release conditions must exist:

- The boiler protection criteria are fulfilled
- The coal bunker filling level is sufficient
- The secondary air temperature downstream air preheaters is > 150 °C (purging and preheating first mill)
- Other release conditions of the coal mills according to the mill process description

The PA fans, which are organized by the firing sequence control program in general, are also switched to operation by the automatic start-up program of the coal mills. Before fan starting also the belonging air preheaters (steam coil air preheaters if required) have to be started. In this connection it should be considered, that the shutoff devices on the air side are opened before the shutoff devices on the flue gas side. When the PA fans are in operation, the flue gas control or trimming dampers will be switched to automatic mode.

For the start of the coal firing system as far as possible all oil burners of the respective starting level should be in operation. All fail-safe criteria of the firing interlocking system to be considered are described in Annex 4.0-1, i.e. the minimum preconditions to be fulfilled for the opening and/or keeping open the safety dampers on the primary air side upstream of each mill and the safety shutoff devices in the downstream PC ducts.

With the start of the first coal mill also the OFA control is switched on.

4.2 Normal Operation

4.2.1 General Firing Plant

In essence, for the boiler operation a kind of heavy fuel oil (HFO) and a range of local bituminous coals with high ash content are foreseen. The ignition and support firing is designed for a maximum firing capacity of 30 % BMCR with 32 burners in service. In addition 8 fuel oil burners can be operated with light Diesel oil (LDO), when no auxiliary steam is available or for boiler cold start-up. The Indian coals can be blended with a maximum amount of 30 % of imported coals.

The steam generator may be operated in pure coal operation in the area from 30 % to 100 % BMCR without oil supporting fire. In this connection see the operational range of the mills and burners in Annex 4.2.1-1. The design coal as reference coal (see specification in Chapter 2.2) is the nominal coal for the control system of the firing plant. The required firing capacity for the relevant load range based on this coal is shown in Annex 4.2.1-2.

The firing plant is prepared for the operation with staged air supply, whereas the combustion air is not only introduced into the furnace by the burners, but also via additional openings as Over Fire Air (OFA). On an average the burner combustion area is operated with slight excess stoichiometry. The remaining air flow required for the complete combustion is introduced into the furnace via the OFA system. The combustion air fuel ratio depending on the boiler load is shown by a diagram in Annex 4.2.1-3.

So the total combustion air flow is a function of the thermal boiler capacity and of the respective excess air ratio. The total heat capacity and the resulting stoichiometric combustion air flow of the boiler are calculated from the measured or simulated fuel flow and the relevant net calorific value (NCV) with the belonging specific combustion air flow. The total rated air flow of the boiler is ascertained by multiplication of the stoichiometric combustion air flow with the load-dependent air ratio. The stoichiometric combustion air flow depending on the firing capacity (fuel heat) as well as the specific combustion air flow is given in Annex 4.2.1-4. The consequential total air mass flow can be read in Annex 4.2.1-5.

`DOCUMENT COVER SHEET

PROJECT NAME : **KUDGI STPP (3 x 800MW) SG Package**

CONTRACT NO. : **CS-9573-102-2-FC-COA-5658**

I T E M : FURNACE PROTECTION SYSTEM

DOCUMENT TITLE : **BMS write-up and other details**

This document is vetted by Q.S.G.M S.W.K

J	2014/08/01	For approval	CD	CD	RM	AM
I	2014/07/02	For approval	CD	CD	RM	AM
H	2014/06/05	For approval	CD	CD	RM	AM
G	2014/04/25	For approval	CD	CD	RM	AM
F	2014/02/11	For approval	CD	CD	RM	AM
E	2013/12/27	For approval	CD	CD	RM	AM
D	2013/09/19	For approval	CD	CD	RM	AM
REV.	DATE	DESCRIPTION	DGN	CHECK	REVW	APPR

एनटीपीसी लिमिटेड
NTPC Limited.
(A Government of India Enterprise)

CONTRACTOR

DOOSAN POWER SYSTEMS INDIA PRIVATE LIMITED

Q.S.G.M

DOOSAN HEAVY INDUSTRIES & CONSTRUCTION Co., Ltd. Korea

CATEGORY		Approval	SHEET	REV.
DOCUMENT NO.	DOOSAN	DT12001-IC-D2007	40	J
	NTPC	9573-102-PVI-T-003	40	09

The following feedback from the igniter is hardwired to the SG-DDCMIS

- HEA ign rod ret fb
- HEA ign rod adv fb
- HEA ign rod dist fb

3.3 Flame Scanner (Refer to "Flame Monitoring System" Doc. No. 9573-102-PVI-Y014)

The purpose of Mill trip at coal flame no detection is to prevent from explosion of unburnt fuel at the furnace. And to prevent from small amount of air flow due to high moisture coal accumulation in the coal pipe. This interlock is for protecting the abnormal conditions.

Implementation of PF firing first requires that the oil burners are lit and a stable flame detected on each of the oil burners associated with the PF burner row that is to be put into service. Each oil burner and each PF burner are equipped with its dedicated flame scanner optimised to detect the flame from its own burner (separate flame scanner for Oil flame -UV scanner) and coal flame scanner-IR Scanner). Please refer to the document Data sheets of Flame monitoring system-9573-102-PVI-Y014.

	Oil	Coal
Model No.	D-LX-200 UAF-10	D-LX-200 IG-10.
Type	UV(Ultra Violet)	IR(Infra Red)
Range	280~ 410nm	780 ~ 1800nm

The flame scanner is suitable for operation in ambient temperature up to 85 degC.
The flame scanner is supplied with cooling air from scanner air fan. The cooling air serves to protect the system mounted on the boiler. It shields the components from hot and/or aggressive gases and dusts.

The following feedback from the flame scanner is hardwired to the SG-DDCMIS

- Flame ON
- Scanner FAULT
- Flame intensity (4-20mA galvanic isolated)

3.3.1 Mill trip philosophy on Flame failure in particular row:

The oil burner is located inside the coal burner and all the burner firing status is permission of coal firingfor that level. It is not permitted to start one mill with another row of oil burners firing.

Mill start permit:

All 5 oil burners for a particular elevation must show "Firing"status (i.e. "Oil flame ON" AND "Individual Oil Burner trip valve"opened)

For example if Mill A is to be started then all the five oil burners for "Row A" must show"Firing"status.

If one(1)oil scanner at row-A is showing "NO flame" or oil burner shutoff valve is closed then "All Oil burner firing"status would not be available and the mill A cannot be started.

Mill trip condition:

- Among 5 coal flame scanner at a row, two (2) or more show No Flame (above 40%TMCR).
- Among 5 coal flame scanner at a row, any flame scanners show No Flame (40%TMCR and less).

4.2.3.2 Mill Shut down sequence (Mill Logic 502,503)

Sequence	Action
1	Ignition burners ON
2	Material feed to MIN
3	PA to MIN
4	Set Mill outlet Temp at Min(54℃)
5	Feeder STOP
6	OPEN cold air damper (Mill OFF temp) (10HFE12AA071)
7	Steam inerting (optional) (120sec time delay)
8	Mill motor current <setpoint?, OR time dely>3min after feeder off. IF YES THEN GO TO 9
9 &	Mill motor OFF
9 &	Mill outlet temperature control OFF
10	Close hot air damper (10HFE12AA071) & hot air gate (10HFE11AA061) Open cold air damper (5%) & cold air gate(100%)
	Decision point : If keeping mill standby condition or not by operator
11	Close cold air damper & cold air gate
12	Close cleaning air damper
13	Close seal air damper
14	Lower rollers (longer still stand)
15	Mill hydraulic OFF
16	Mill gearbox lubrication OFF
17	END - Plant out of operation

& (And)			≥1 (OR)		
Input 1	Input n	output	Input 1	Input n	output
0	0	0	0	0	0
0	1	0	0	1	1
1	0	0	1	0	1
1	1	1	1	1	1

4.3 Mill Inerting and Fire Fighting System

- Reference P&ID: 9573-102-PVM-L022 ~ L024

The purpose of the proposed pulverizerinerting and fire fighting is to dilute the oxygen content of the pulverizer when the risk of a pulverizer explosion is increased, to maintain an inert atmosphere in the pulverizer with steam, and to extinguish fires in the pulverized fuel system. This system provides a method to safety control a fire and to reduce the risk of explosions in direct fired pulverizer fuel systems. Of primary concern is assuring the safety of plant personnel during a potentially hazardous situation.

Hazardous conditions that can lead to pulverizer explosions are :

- A trip of pulverizer containing fuel.
- An interruption in fuel feed to an operating pulverizer
- A hot non-working pulverzer containing fuel.

Pulverizer fires are usually caused by :

Coal Firing Interlocking Matrix => Release Criteria for Burner Level 10

1. Coal - Start-up - Release

Level 70	Level 80		Level 70	Level 80		Level 70	Level 80		Level 70	Level 80	
Level 50	Level 60	or	Level 50	Level 60	or	Level 50	Level 60	or	+ 3 of 4 IR or UV	+ 3 of 4 IR or UV	or
Level 30	Level 40		Level 30	Level 40		+ 3 of 4 IR or UV	+ 3 of 4 IR or UV		Level 50	Level 60	
4 of 4 UV			3 of 4 UV	+ 3 of 4 IR or UV		Level 30	Level 40		+ 3 of 4 IR or UV	+ 3 of 4 IR or UV	
Level 10	Level 20		Level 10	Level 20		3 of 4 UV			Level 30	Level 40	
						Level 10	Level 20		2 of 4 UV	+ 2 of 4 IR or UV	
									Level 10	Level 20	

2. Coal - Operational - Release

Level 70	Level 80		Level 70	Level 80		Level 70	Level 80	
Level 50	Level 60	or	Level 50	Level 60	or	Level 50	Level 60	or
Level 30	Level 40		Level 30	Level 40		+ 3 of 4 IR or UV	+ 3 of 4 IR or UV	
3 of 4 IR or UV			2 of 4 IR or UV	+ 3 of 4 IR or UV		Level 30	Level 40	
Level 10	Level 20		Level 10	Level 20		2 of 4 IR or UV		
						Level 10	Level 20	

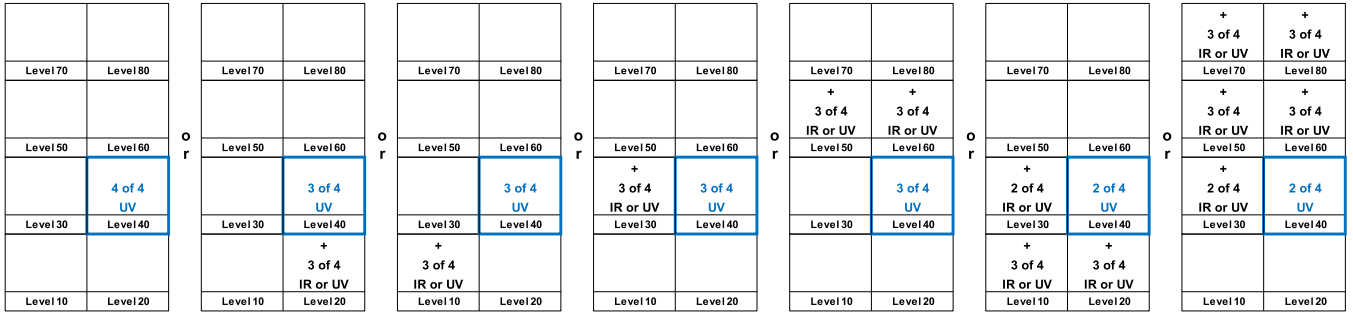
3. Coal - Restricted Operational - Release

Level 70	Level 80		Level 70	Level 80		Level 70	Level 80	
Level 50	Level 60	or	Level 50	Level 60	or	Level 50	Level 60	or
Level 30	Level 40		Level 30	Level 40		+ 3 of 4 IR or UV	+ 3 of 4 IR or UV	
2 of 4 UV			- / -	+ 3 of 4 IR or UV		Level 30	Level 40	
Level 10	Level 20		Level 10	Level 20		- / -		
						Level 10	Level 20	

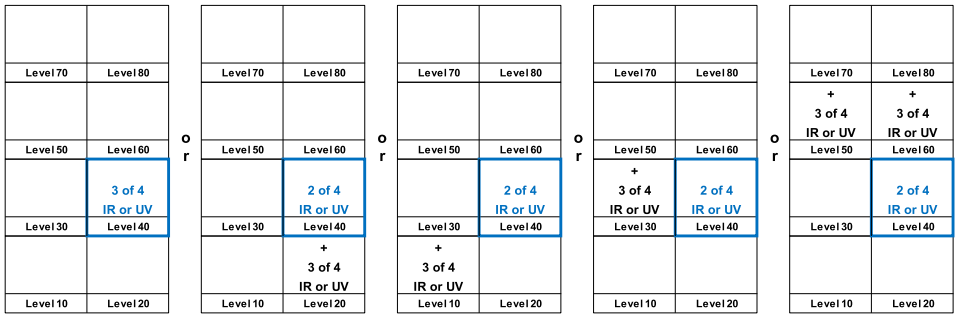
4. Legend => See attached common sheet for all levels

Coal Firing Interlocking Matrix => Release Criteria for Burner Level 40

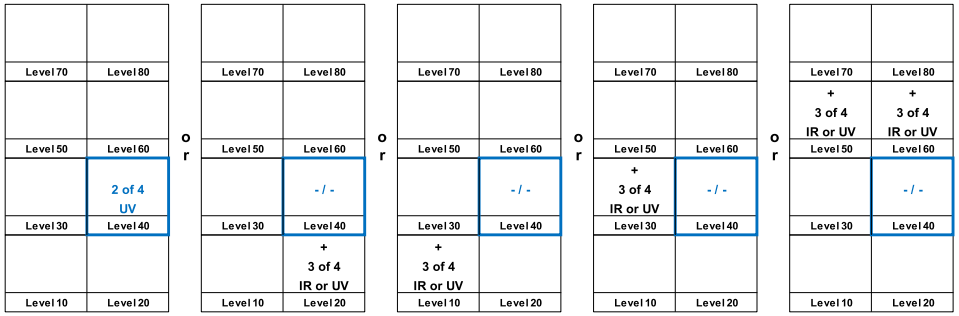
1. Coal - Start-up - Release



2. Coal - Operational - Release



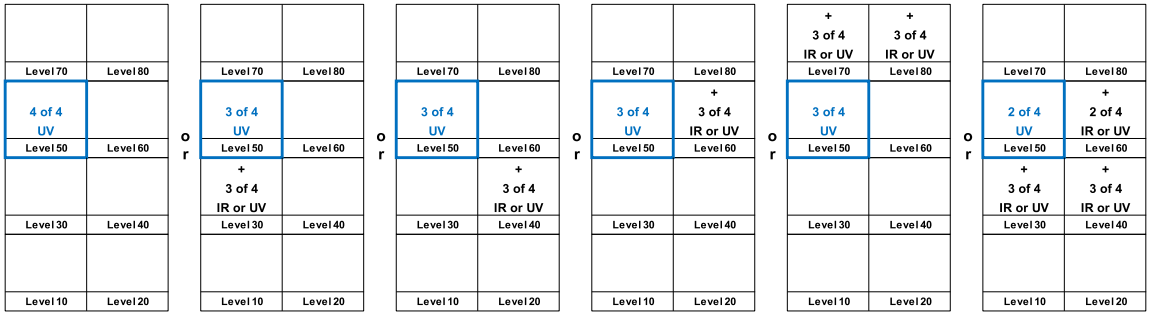
3. Coal - Restricted Operational - Release



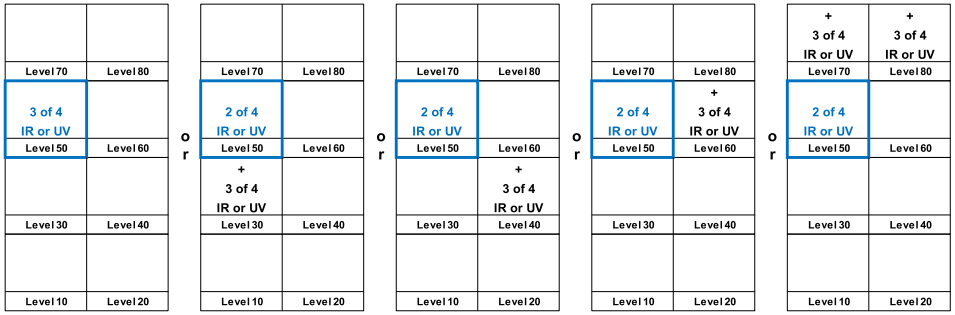
4. Legend => See attached common sheet for all levels

Coal Firing Interlocking Matrix => Release Criteria for Burner Level 50

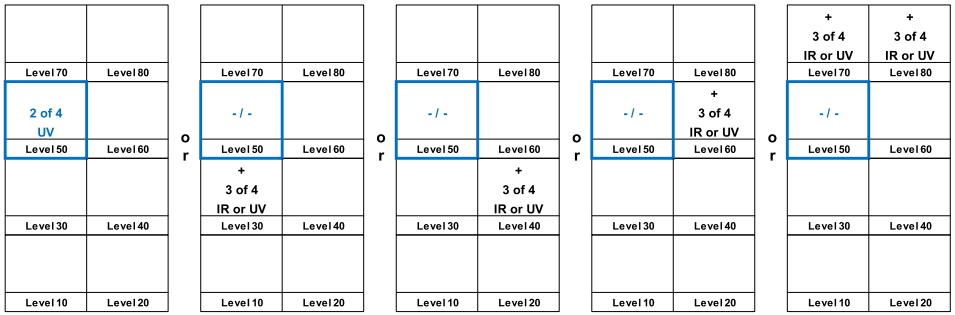
1. Coal - Start-up - Release



2. Coal - Operational - Release



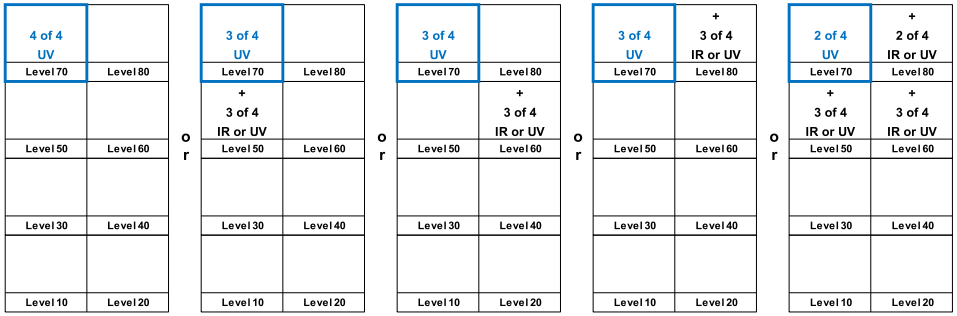
3. Coal - Restricted Operational - Release



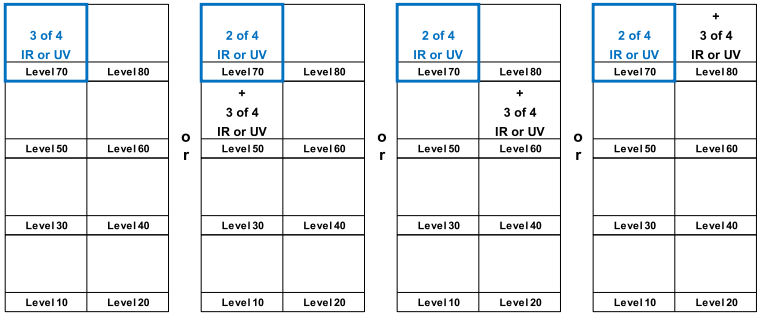
4. Legend => See attached common sheet for all levels

Coal Firing Interlocking Matrix => Release Criteria for Burner Level 70

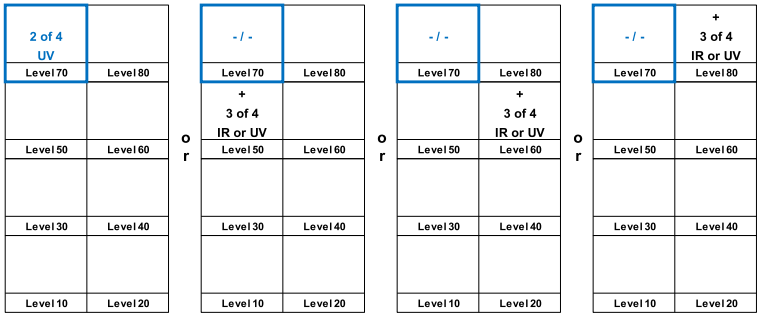
1. Coal - Start-up - Release



2. Coal - Operational - Release



3. Coal - Restricted Operational - Release



4. Legend => See attached common sheet for all levels

4. Legend to Coal Firing Interlocking Matrix for all Burner Levels

1. Coal - Start-up - Release:

The **Coal - Start-up - Release** discribes the minimum firing conditions that must be fulfilled prior to starting up the coal firing system in the respective burner level.
The release is cancelled 5 minutes after start-up of the coal feeder.

2. Coal - Operational - Release:

The **Coal - Operational - Release** discribes the minimum firing conditions that must be fulfilled for continuous operation of the coal firing system in the respective burner level.

3. Coal - Restricted Operational - Release:

The **Coal - Restricted Operational - Release** discribes the minimum firing conditions that must be fulfilled for temporary operation of the coal firing system in the respective burner level, whereas the relevant coal mill has to be switched off by the "Accelerated Shutdown Program". The release is cancelled 10 minutes after coal feeder shutdown.
At the latest then the safety dampers in the primary air ducts upstream of the mill are closed.

The different release conditions for the firing system in addition to the superior boiler protection criteria are finally the release conditions for the opened safety dampers in the primary air ducts upstream of the relevant coal mills as well as the shutoff devices in the downstream PC ducts. If the required release criteria are not fulfilled, the relevant safety shutoff devices are closed immediately to interrupt the fuel flow into the furnace.

4 of 4 UV	=>	4 of 4 UV flame signals by the oil burners in the designated level with a fuel capacity > MIN (= 30 MW)
3 of 4 UV	=>	3 of 4 UV flame signals by the oil burners in the designated level with a fuel capacity > MIN (= 22.5 MW)
2 of 4 UV	=>	2 of 4 UV flame signals by the oil burners in the designated level with a fuel capacity > MIN (= 15 MW)
3 of 4 IR or UV	=>	3 of 4 IR flame signals by the coal burners in the designated level with a fuel capacity > MIN (= 110 MW) or 3 of 4 UV flame signals by the oil burners in the designated level with a fuel capacity > MIN (= 22.5 MW)
2 of 4 IR or UV	=>	2 of 4 IR flame signals by the coal burners in the designated level with a fuel capacity > MIN (= 110 MW) or 2 of 4 UV flame signals by the oil burners in the designated level with a fuel capacity > MIN (= 15 MW)
- / -	=>	No flame signals by the burners in the designated level required